NON-PUBLIC?: N
ACCESSION #: 8901230349
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Oconee Nuclear Station, Unit 3 PAGE: 1 OF 11

DOCKET NUMBER: 05000287

TITLE: Reactor Trips due to unknown cause and equipment failure
EVENT DATE: 11/14/88 LER #: 88-006-00 REPORT DATE: 01/13/89

OPERATING MODE: N POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50/73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Philip J. North, Regulatory Compliance TELEPHONE: 704-373-7456

COMPONENT FAILURE DESCRIPTION:
CAUSE: F SYSTEM: TQ COMPONENT: 39 MANUFACTURER: SAIC
REPORTABLE TO NPRDS: NO

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On November 14, 1988, at 0724 hours while operating at 100% full power, the Unit 3 Main Turbine (MT) tripped resulting in an anticipatory reactor trip. An investigation into the incident did not identify the cause of the MT trip. Subsequently, at 1130 hours the same day, permission was received to restart the reactor. At 1737 hours, with the reactor at 39% full power, the MT tripped again initiating a runback in reactor power by the Integrated Control System (ICS). At 1738 bours the Reactor Coolant System pressure reached the trip setpoint and tripped the reactor from 35% full power. The cause of this MT trip was determined to be a partially grounded Once Through Steam Generator (OTSG) High Level Trip Signal Monitor. The immediate corrective action was to stabilize the unit at hot shutdown. The supplemental corrective actions included determining the cause of the unit trip and replacing the faulty signal monitor. The root cause of the initial unit trip could not immediately be determined. The root cause of the second unit trip was a ground fault in the OTSG High Level Trip Signal Monitor.

END OF ABSTRACT

INTRODUCTION

On November 14, 1988, at 0724 hours while operating at 100% full power, the Unit 3 Main Turbine (MT) (EIIS:TRB) tripped resulting in an anticipatory reactor (EIIS:RCT) trip. An investigation into the incident did not identify the cause of the MT trip. Subsequently, at 1130 hours the same day, permission was received to restart the reactor. During power escalation at 1737 hours, with the reactor at 39% full power, the MT tripped again initiating a runback in reactor power by the Integrated Control System (ICS) (EIIS:JA). At 1738 hours the Reactor Coolant System pressure reached the trip setpoint and tripped the reactor from 35% full power. The cause of this MT trip was investigated and determined to be a partially grounded Once Through Steam Generator (OTSG) (EIIS:SG) High Level Trip Signal Monitor (EIIS:39).

The immediate corrective action was to stabilize the unit at hot shutdown. The supplemental corrective actions included determining the cause of the unit trip and replacing the faulty signal monitor.

The root cause of the initial unit trip could not immediately be determined. Therefore, this incident is classified as unknown. The root cause of the second unit trip was a ground fault in the OTSG High Level Trip Signal Monitor which initiated Customer Trips Relay in the Electrohydraulic Control (EHC) system (EIIS:TQ). Therefore, the second unit trip is classified as an equipment malfunction.

BACKGROUND

The Once Through Steam Generator (OTSG) produces superheated steam and provides a barrier between the primary and secondary sides of the system to prevent fission products and activated corrosion products from entering the Secondary Steam System. The Main Turbine (MT) and Main Feedwater Pumps (MFDWP) are equipped with an OTSG High Level Trip Signal Monitor which protects the MT from water induced damage. This High Level Trip Signal Monitor trips the MT and MFDWP to prevent water carry over into the Main Steam lines and the high pressure turbine in the event OTSG Feedwater (FDW) levels reach 92% of the operating range. Feedwater control is also a function of the Integrated Control System (ICS).

The ICS at Oconee is used to assist the Nuclear Control Operators in properly controlling the Main Steam (EIIS:SB) supply at power. The system is designed to coordinate the thermal power of the reactor with the heat removal capability of the two OTSG's during both steady state and transient operating modes. The ICS maintains total FDW flow equal to FDW flow demand and parallels this with reactor power level.

The purpose of the First Hit Circuit is to annunciate, through a series of lamps on the turbine monitor panel which event of several tripping events, occurred first to trip the turbine. The response time of the circuit is three milli-seconds. If any trip signals are more than three milliseconds apart, the circuit will distinguish between them and cause only one light to light.

Customer Trips are a number of parallel contacts in the ONS protection system which energize a common relay (KT805) to energize the master trip and alarm circuits. Items that feed the Customer Trips relay are: High OTSG Level, Turbine oil fire, Generator Lockout, and two sources of both main feedwater pumps tripped.

DESCRIPTION OF OCCURRENCE:

At 0724 hours on November 14, 1988, with Unit 3 operating at 100% full power, the Main Turbine (MT) tripped. This resulted in an anticipatory reactor trip signal from the MT trip circuitry and a subsequent reactor trip.

After the trip, Unit 3 Assistant Shift Supervisor inspected the Electrohydraulic Control (EHC) first hit panel and could not locate any indication as to what caused the MT trip. Operations then initiated a Work Request 18805C to have the Instrument and Electrical (IAE) Department perform an investigation into the cause of the trip. At 0914 hours the NRC was notified via the red phone of the Turbine/Reactor trip pursuant to 10 GFR 50.72.

The IAE Department immediately examined the Events Recorder (ER) printout and the Operator Aid Computer (OAC) printout. These printouts revealed none of the normal EHC trip signals were present. IAE inspected the EHC first hit panel and determined the Generator Lockout Relay 86GA and 86GB relays tripped normally; also, the PS100 A&B pressure switches actuated normally. The first hit circuitry did not reveal the actual cause of the trip. Since nothing could be found to identify the cause of the trip, and since no indications were recorded on the ER or OAC, IAE concluded the trip cause was something that was not connected to either. This left two possible causes for the trip: a mechanical fault in the overspeed governor, or the mechanical trip handle was pulled. IAE initially thought

the Customer Trips input could have been the cause, but ruled out most of the possibilities there. Since neither feedwater pump tripped, OTSG high level was eliminated. Since both feedwater pumps are required to be tripped for the loss of feedwater pumps tripped, a single failure in the circuitry would not cause a fault. Therefore, the "both feedwater pumps tripped" inputs were eliminated by IAE. All of the required EHC oil pumps were running, and no ER or OAC points corroborated, so the Turbine Oil Fire trip was eliminated. The only Customer Trip left was Generator Lockout, but since the ER indications appeared to be normal, there was no way for IAE to prove this to be the cause. IAE informed Operations that the exact cause of the trip could not be identified and that all systems appear to be functioning normally. Subsequently, at 1130 hours permission to restart the reactor was received from the Operation's Shift Supervisor, Shift Engineer, and the Unit Engineer.

At 1427 hours the turbine-generator was placed on line. Reactor power was increased 7% per hour. At 1737 hours, with Unit 3 at 39% power, the MT tripped for a second time. This trip initiated an automatic Integrated Control System (ICS) controlled reactor power runback. At this instance the ICS ran back reactor power from 39% full power to 35% full power. At 35% full power Reactor Coolant System (RCS) pressure reached the trip setpoint and tripped the reactor. IAE was again requested to investigate the cause of the trip. The NRC was notified at 1936 hours, via the red phone, of the second Turbine/Reactor trip pursuant to 10 CFR 50.72.

After the second trip, IAE determined the EHC first hit circuitry definitely showed the Customer Trips input as the cause. Using the same logic as before, IAE determined the Generator Lockout to be a likely cause. IAE then performed a review of the electrical drawings. This review showed that the 86GA relay caused the turbine trip, and the 86GB relay caused the ER to print out. Since these are two separate devices, IAE felt that the GA relay could have caused the trip, and it would not have shown up on the ER until the actual Generator Lockout occurred sometime later. However, testing of the 86GA relay did not reveal any problems, and the OAC, which monitors both generator lockout relays, showed normal actuation of both.

Since the Customer Trips Relay KT805 in the EHC system definitely was the first hit, causing the turbine trip, and since no valid input could be found that caused the trip, IAE concluded that everything worked correctly and a circuit fault must have been the cause. IAE then remembered that ground faults had previously been discovered in a new Science Application International Corporation (SAIC) Signal Monitor module installed on

another unit. It was also remembered that four of these signal monitors had been installed during the Unit 3 EOC-10 refueling outage. These signal monitors were installed in the OTSG High Level Trip Circuitry.

IAE then measured the circuitry surrounding the KT805 relay and a voltage potential was found across the relay, thus indicating a small current flow. The OTSG High Level Trip Signal Monitors were pulled one at a time, and the module in location 14-2-8 was found to be the cause of the current flow through the trip relay. Subsequently, IAE determined the cause of the second trip to be a ground fault circuit path causing the Customers Trip Relay KT805 to energize. The faulty OTSG High Level Trip Signal Monitor was replaced. At 0240 hours on November 15, permission was received from the Superintendent of Operations and the Operations Duty Engineer to restart the reactor. At 0727 hours the turbine-generator was placed on line, and on November 16, at 0453 hours Unit 3 reached 100% full power.

Following the initial reactor trip the unit was stabilized at hot shutdown. The Main Feedwater Pumps did not trip and consequently, no actuation of the emergency feedwater system was incurred. RCS pressure ranged from 2140 psig just prior to the trip, to a minimum of 1820 psig, to a maximum of 2190 psig. Hot leg temperatures ranged between 601 degrees F to 555 degrees F for both loops. Cold leg temperatures ranged between 550, degrees F to 558 degrees F. Pressurizer response was as expected with a nominal operating value of 220 inches prior to the trip to a minimum of 70 inches before recovery. OTSG levels remained above 25 inches. The ICS response was as expected. Also, all remaining plant responses were normal with the exception of lowering Main Steam pressure to 960 psig to reseat Valve 3MS-8, and 3FDW-40 going from auto to manual and remaining open following the trip. There was no apparent RCS leakage and no actuation of Engineered Safeguards (ES) systems or pressurizer relief valves during this incident.

Following the second reactor trip the Unit was again stabilized at hot shutdown. The reactor trip occurred when RCS pressure reached the trip setpoint. The increase in RCS pressure was the result of the Reactor's inability to runback as fast as the feedwater system. The response of plant systems after the trip were primarily normal. However, several abnormal equipment responses in addition to the ground fault which caused the MT trip occurred during the second transient. The first included the main feedwater block valves 3FDW-31 and 3FDW-40 going to manual and remaining open following the reactor trip. When Nuclear Control Operators (NCO) placed the valves back into automatic mode, they immediately closed

and remained closed. This occurrence could not be reproduced during post-trip evaluations. This abnormal response did not affect the control of OTSG levels during the transient. Another failure which did not affect post-trip transient response was the failure of the generator exciter field breaker to trip due to mechanical binding. The breaker was replaced prior to unit restart. Also, during the transient all power was lost to the 600 volt Motor Control Center panel 3XD. This panel supplies power to the feedwater pump turning gear motor, the stator coolant pump, and the turbine building sump pump. Loss of power to this panel did not affect post-trip transient response. It was noted that turbine bypass valve 3M-22 did not open in a timely manner following the trip. Normal response of the bypass valves is to open within 4 seconds of the trip, 3MS-22 opened 24 seconds after the trip. However, this did not affect post-trip transient response. The final equipment problem involved the leaking of 3MS-8. The NCO was forced to lower steam header pressure to 960 psig to fully reseat the valve. RCS pressure decreased from its trip value of 2345 psig to a minimum of 1960 psig before recovery. Hot leg temperatures ranged from a pre-trip value of 586 degrees F for both loops to a post trip value of 548 degrees F. Cold leg temperature varied from a pre-trip value of 570 degrees F to a post trip value of 548 degrees F. The pressurizer responded normally from a trip value of 260 inches to 120 inches at recovery. OTSG levels were adequate with minimum levels of 24 inches for both OTSG A and B. ICS response was normal and no apparent RCS leakage occurred. There was no actuation of the ES system or pressurizer relief valve.

CAUSE OF OCCURRENCE:

It is concluded that although the initial Unit 3 Reactor trip was an anticipatory trip caused by a Main Turbine (MT) trip at 100% full power, the root cause of the MT trip could not be determined. This conclusion is based on the fact that Instrument and Electrical (IAE) could not positively identify the cause of the trip even after an extensive troubleshooting analysis had been performed. Therefore, the root cause of the initial Turbine/Reactor trip is classified as unknown.

It is concluded that Nuclear Control Operators' (NCO's) response during the initial trip was appropriate. This conclusion is based on the fact that following the trip NCO' s responded and stabilized the unit at hot shutdown conditions. It is also concluded that two system anomalies occurred during the initial trip. This conclusion is based on the fact that Main Steam (MS) pressure had to be lowered to reseat 3MS-8, and 3FDW-40 went from auto to manual and remained opened during the transient.

It was determined by the Mechanical Engineering Support (MES) Section that the last inspection of 3MS-8 was performed, during the routine preventative maintenance schedule, in September, 1985, with no problems found. This valve is scheduled for maintenance during the next Unit 3 EOC-11 refueling outage. MES also determined that although lowering the MS pressure to 960 psig to reseat 3MS-8 is abnormal, this coincides with an 8.22% blowdown rate and is therefore acceptable.

It is concluded that the cause of the second Turbine/Reactor trip was due to a ground fault circuit path initiating the Customer Trips Relay KT805 in the Electrohydraulic Control (EHC) system. Therefore, the root cause of the second trip is classified as an equipment malfunction. It is concluded that the Once Through Steam Generator (OTSG) High Level. Trip Signal Monitor was the equipment which malfunctioned. This conclusion is based on the fact that IAE identified a ground fault in this monitor caused by a defective relay. The monitor is a Science Application International Corporation (SAIC) signal monitor; Model RP2049-2; Part Number 1138860100. It is also concluded that the sensitivity of the faulted circuit in the signal monitor was greater than the sensitivity of the ground fault detection relay. This conclusion is supported by the fact that although a ground fault existed, no indication of a ground fault was detected before alarms or Unit trips were actuated. It would appear that proper trip actuation relay coordination would have the trip relays less sensitive than the ground detection relays, and energizing faults would not cause a unit trip without warning.

It is concluded that during the second transient, Unit 3 Reactor tripped due to high Reactor Coolant System (RCS) pressure. This conclusion is based on the fact that the Integrated Control System (ICS) responded properly or as it was designed during the transient. Following the MT trip, steam pressure rapidly increased to 1050 psig in OTSG "A" and 1000 psig in OTSG "B". With the reactor at 39% full power, the ICS initiated an automatic power runback to 15% at a rate of 20% per minute. The rapid increase in steam pressure over the normal setpoint created a strong signal to decrease both reactor and total feedwater demand signals much faster than 20% per minute. The Loop "A" and "B" feedwater valves and the operating feedwater pump were able to follow the decreasing feedwater demand, but the control rods, which were continuously inserting, were not able to decrease reactor power at the same rate. After 26 seconds of mismatch between reactor power and feedwater flow, the average RCS temperature had increased 8*F and raised the RCS pressure to the high pressure trip point of 2345 psig. The Reactor Protection System then

tripped the reactor on high RCS pressure. It is also concluded that the abnormal equipment responses experienced during the second transient had no adverse affect on post-trip transient response.

A review of past station incidents revealed that there have been no other unit trips in the past three years due to an unknown cause, but there have been nine unit trips due to equipment malfunction/failure. However, none of these trips were due to a faulty OTSG high level trip signal monitor. The malfunction of the OTSG High Level Trip Signal Monitor is not NPRDS reportable. No personnel injuries, radiation exposures, or releases of radioactive material resulted from these unit trips.

CORRECTIVE ACTIONS:

The immediate corrective action was to stabilize the Unit at hot shutdown conditions.

Subsequent corrective actions were to:

Replace the faulty Once Through Steam Generator High Level Trip Signal Monitor.

Investigate the problem of loss of power to the 600 volt Motor Control Center panel.

Replace the faulty generator exciter field breaker.
Generate a Station Problem Report to address problems between the interaction of feedwater demand and reactor demand during runbacks from moderate power levels.

Planned corrective actions are to:

Test the Science Application International Corporation (SAIC) Signal Monitor Relays installed on Units 1, 2, 3 during the next refueling outage for each unit.

Test spare SAIG Signal Monitor Relays in current stock prior to installation.

Examine the block valve circuitry on feedwater valves 3FDW-31 and 3FDW-40 to ensure no wiring problems or component failures exist.

Investigate the problem of turbine bypass valve 3MS-22 not opening in a timely manner.

Resolve problems which exist in the interaction of feedwater demand and reactor demand during runbacks from moderate power levels.

ANALYSIS OF OCCURRENCE:

Following the first reactor trip, the unit was stabilized at hot shutdown, emergency feedwater was not actuated, and the ICS response was as expected. Unexpected was that main feedwater block valve 3FDW-40 went from automatic to manual and remained open, but this response did not affect the control of the steam generator levels because feedwater was controlled by the control valves. A review of the FSAR showed no reliance on main feedwater block valves for accident mitigation. Also, main steam pressure had to be lowered to 960 psig to reset main steam relief valve (MSRV) 3MS-8. The minimum post-trip RCS temperature was approximately 548 degrees F.

For background information, the feedback of a rapid steam pressure increase on feedwater demand and reactor demand signals was initially designed to aid the ICS in storing and borrowing energy to and from the steam generators as needed to maintain constant steam pressure at the inlet of the turbine. During a turbine trip, after which ICS will automatically run back reactor power, the storing and borrowing of energy is not as important as maintaining a good balance between total feedwater flow and reactor power so that undesirable heating of the RCS will not occur.

Concerning the second trip, the turbine trip from 39% reactor power should have resulted in the plant successfully running back to approximately 15% reactor power without tripping. For Oconee, the anticipatory reactor trip arming threshold is set at 50% reactor power. Analysis has shown that an Oconee unit can successfully runback from trips below this power level when the reactor and feedwater control responses are properly matched.

The second turbine trip and subsequent unsuccessful reactor runback was due to total feedwater flow being reduced significantly lower than reactor power. Upon the turbine trip, main steam pressure increased rapidly. Two simultaneous effects were occurring within the ICS as a result of the rapid increase in steam pressure. When steam pressure exceeded its

setpoint, the error signal reduced the total feedwater demand signal. Also, the increased steam pressure reduced the feedwater flow to both steam generators because of the higher back pressure against the pumps.

The ICS initiated an automatic power runback to 15% at a rate of 20% per minute. The rapid increase in steam pressure created a strong signal to decrease both reactor and total feedwater demand signals much faster than the 20% per minute. The main feedwater system was able to follow the decreasing feedwater demand, but the control rods were not able to decrease reactor power at the same rate. To correct this mismatch in decrease rates, the ICS reopened the main feedwater valves, but the increase in feedwater flow was not in time to prevent the reactor coolant system from increasing temperature and pressure to the high pressure trip setpoint of 2345 psig. The reactor trip immediately terminated the pressure transient.

Like the first trip, there were some unexpected equipment responses that did not affect the post-trip transient response. Main feedwater block valves 3FDW-31 and 3FDW-40 went from automatic to manual and remained open. When the operators placed the valves back into automatic mode, the valves closed. The control valves provided the proper post-trip feedwater control. Also, as before, operators had to lower main steam pressure to 960 psig to reseat MSRV 3MS-8. Another failure which did not affect the post-trip transient response was the failure of the generator exciter field breaker to trip due to mechanical binding.

In 1979, several changes were made to B&W plants in order to reduce challenges to the pressurizer's Power Operated Relief Valve (PORV). The changes made to achieve this reduction were: raising the PORV opening setpoint from 2255 psig to 2450 psig, lowering the setpoint for reactor trip on high RCS pressure from 2355 to 2300 psig, and implementing an anticipatory trip (ART) on turbine trip for reactor power levels of 20% and above.

Within the last two years, B&W plants have been raising the RCS high pressure trip setpoint back to the original 2355 psig. By increasing this setpoint, plants have been able to raise the ART threshold to 40-50%. The reason for adjusting the ART threshold is to improve plant availability by reducing reactor trips and to improve safety by reducing challenges to safety systems. All of the above changes were done under the condition that NRC requirements regarding the PORV are met. The two requirements are : 1) The probability of a small-break LOCA due to a stuck-open PORV

must be less than 0.001 per reactor year and 2) Less than 5% of the high pressure trips are alloWed to open the PORV. Both of these requirements are met with the RCS high pressure trip setpoint at 2355 psig. The probability of a small-break LOCA due to stuck-open PORV is now 2.53E-4 and it is estimated that 0.001% of the overpressure transients allow the PORV to open.

The real safety issue on which the focus should be placed is whether the NRC requirements concerning the PORV have been violated and if the pressurizer PORV was opened. While the reactor did not successfully run back as anticipated, the trip on high RCS pressure was fully consistent with the analyses performed to justify raising the trip setpoint to 2355 psig. Included in these analyses is the Unreviewed Safety Question Evaluation which states that the increasing of the arming threshold seeks to reduce (not eliminate) the number of reactor trips below 50% power and that the most significant piece of equipment related to this increase, the pressurizer PORV, is unaffected by the change (i.e., the frequency of PORV challenge is neither affected by the ART threshold nor the success or failure of the reactor to runback). The frequency of challenge to the PORV is determined by the PORV setpoint and the margin between it and the RCS high pressure trip setpoint. Analyses have shown that the 2355 psig trip setpoint ensures that the PORV challenge frequency is maintained below 0.001.

The maximum RCS pressure experienced during this transient was approximately 2345 psig. (The RCS high pressure trip setpoint is set at 2345 psig to give a margin against tripping above the 2355 psig level due to instrument error.) This pressure response did not result in the pressurizer PORV opening.

In both of these trips, no actuation of the Engineered Safeguards System or radioactive releases occurred. Based on the preceding analysis, the health and safety of the public were not affected.

ATTACHMENT 1 TO 8901230349 PAGE 1 OF 1

Duke Power Company HAL B. Tucker
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DUKEPOWER

January 13, 1989

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
LER 287/88-06

Gentlemen:

Pursuant to 1OCFR 50.73 Sections (a) (1) and (d), attached is Licensee Event Report (LER) 287/88-06 concerning Unit 3 reactor trips on November 14, 1988. My letter of December 14, 1988 informed you of the delay in submitting this report.

This report is being submitted in accordance with 10 CFR 50.73(a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

Hal B. Tucker

PJN/ler3

Attachment

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*** END OF DOCUMENT ***